# ComEd's Alternative to NFF Market Index Proposal

## Description

The following outlines ComEd's proposal to replace the NFF in establishing the market values used in calculating transition charges (TC) and setting PPO rates. This proposal follows the structure of the generic market index proposal supported by Ameren, Commonwealth Edison, and Illinois Power. This plan could be implemented prior to the start of the customer billing cycles for Summer of 2000. Once instituted, all customers choosing the PPO option would have their rates and TC's calculated based on market values derived through this new proposal. Current PPO customers would be given the option of remaining with their current terms through the end of their current contract (the current rates and TC's would end on or before December 31, 2000), or choose a new 12-month PPO contract commencing June 1, 2000. Except for existing PPO customers choosing the grandfather option, all PPO rates and TC's would be calculated with the new methodology after June 1, 2000.

This alternative proposal would establish separate market values for each customer class during four periods: summer peak, summer off-peak, non-summer peak, and non-summer off-peak. Annual price setting would occur in mid-April of each year to establish market values from June of the current year through May of the following year. There would be a second price setting for each year during July to re-establish values from September through May of the following year. These second prices would only apply to customers first electing Delivery Service during those months. The newly established values would be reflected in new PPO rates and TC's for periods going forward. Thereafter in June of each year, all Delivery Service customers would be subject to new market values, determined in the previous April, that would then apply for the next 12 months.

## Pricing Mechanics

Through market indices, the market values would reflect the price of energy bought and sold in the Into ComEd hub. ComEd proposes that Into ComEd forward prices would be determined using transaction prices along with bid/ask prices from Altrade™ and Bloomberg PowerMatch: two real time, online electronic trading exchanges which post Into ComEd forward market prices. These forward prices would be used to quantify the peak period prices since this is the most volatile pricing period. Off-peak pricing would utilize historical day-ahead data from "Power Markets Week's *Daily Price Report*" published by McGraw-Hill for the most representative region for ComEd's service territory (currently Northern MAIN).

### *Peak Price Indices*

Forward prices for the summer period (June, July, August and September), would be established from separate monthly prices (although July and August would each use the same value as reported for the combined July/August period). By determining these forward prices in April (which is very close to the corresponding summer), this methodology establishes a reasonable approach for summer forecasts. The prices in non-summer peak periods are much less volatile, but would also be based on available monthly forward transaction prices and reasonable bid/ask price quotes. Daily weighted average transaction prices, or when necessary "best market" bid/ask midpoints , would be recorded for each given forward delivery period. These daily "snapshots" would be averaged over a one month period ending in April and July to arrive at estimated on-peak market prices for the two price setting periods. Other means to validate reasonable inputs may be instituted. The monthly average price would be used to scale hourly price shapes to create hourly prices relevant to Illinois.

*Off-Peak Price Indices*

The off-peak prices from "Power Markets Week's *Daily Price Report"* would provide monthly a range of values of historical prices based on day-ahead quotes. These quotes are based on surveys taken for transactions on weekdays. The simple average of low-high daily price quotes would be used to establish a monthly average price for the 1X8 weekday off-peak period. This proposal would use these prices to adjust the 1999 PJM-West (Pennsylvania, New Jersey, Maryland) hourly pricing information, to establish off-peak prices relevant to Illinois.

*Price Shaping*

It is also proposed that PJM-West data be used to develop hourly price shapes for each monthly peak and off-peak period. There already exist hourly PJM-West price data for the 8760 hours in 1999. By using an hourly price shape one can translate an average block price into hour-by-hour market values. The monthly forward price for each monthly on-peak period can be divided by the same month's average on-peak price from PJM-West to establish an on-peak price ratio. Similarly, the monthly average values for each month's 1X8 price strip can be divided by the corresponding average monthly 1X8 prices from PJM-West data to establish a monthly off-peak price ratio. Each month'sappropriate on-peak and off-peak price ratio would be multiplied by the price in every hour in each month's on-peak and off-peak period, respectively. This off-peak ratio is also applied to the entire weekend period. The following paragraphs describe creating typical price profiles for each month.

Using the 1999 PJM-West hourly price data, a typical 24-hour weekday price shape can be calculated for each month. Segregating weekdays (which are not holidays) in a given month, the simple average of hour one prices would become the hour one typical weekday price. The remaining 23 hours can then be separately averaged in the same manner. Next the holidays and weekend days would be grouped and averaged for each hour calculated. The same process continues on with the next month. The final results are two 24-hour typical price shapes, one for weekdays and one for weekend/holidays for each of the 12 months. Since these calculations are based only on PJM-West data, these price shapes could apply to any region that approximates PJM-West in price shape.

By multiplying these typical price shapes by the on-peak and off-peak price ratios from above, the price shape would reflect the expected typical hourly prices based on market indices chosen. The resulting hourly prices would represent the system market values which correspond with typical system loads for the same periods. The first step towards translation for customer classes is to increase each hourly price to account for transmission losses. All this can be done prior to introducing specific customer class information.

Since there are typical load shapes for each customer class, it is possible to calculate an expected load weighted cost of energy and power for individual customer classes for each month. This is done by multiplying the appropriate matrix of prices by the corresponding matrix of customer specific loads and dividing by the summation of those loads. At this point, the information becomes customer class specific and adjustment factors currently in applicable tariffs for distribution losses, sales, marketing, and uncollectibles can be applied. The final peak and off-peak prices for summer and non-summer periods would be the load weighted price averaged over the appropriate time period.

However, developing the hour-by-hour market values and multiplying load shapes would eliminate the need to ratio the system market values to include intra-day pricing effects currently in tariffs. In fact, these price shapes should provide a very accurate means to approximate each customer class' load weighted hourly market values, i.e. the average cost of expected usage. Also the hourly load-weighted market values allow for flexibility to determine each customers class' average cost for different period definitions (e.g.,13 hour versus 16 hour peak periods).

## Summary

This methodology is meant to rely on relevant market information. As electricity markets improve in Illinois, hourly price data may shift from PJM-West to posted hourly prices from Illinois power exchanges, and forward pricing may be extracted from additional sources. This basic market index methodology would still be applicable but improved with better information. The market index methodology can be used by all utilities to determine appropriate market values needed for calculations of PPO rates and transition charges in lieu of the current NFF process.